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PUBLIC UTILITIES COMMISSION

June 26, 2003

VIA HAND DELIVERY

Luly Massaro, Commission Clerk
Public Utilities Commission
89 Jefferson Boulevard
Warwick, RI 02888

Re: Docket No. 3436

Dear Luly:

Enclosed are an original and nine (9) copies of the Direct Testimony of Peter C. Czekanski and Gary L. Beland in the above-referenced Docket. In compliance with Commission Order No. 17444, included within Mr. Czekanski's testimony is a proposal to address the impacts of reverse migration.

Sincerely,

CRAIG L. EATON, #5515
Attorney for New England Gas Company
CLE/kmb
Enclosure

cc: Service List

STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS
PUBLIC UTILITIES COMMISSION

NEW ENGLAND GAS COMPANY
DOCKET NO. 3436

DIRECT TESTIMONY

OF

PETER C. CZEKANSKI

June 26, 2003

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Peter C. Czekanski. My business address is 100 Weybosset Street, Providence, RI 02903.

Q. WHAT IS YOUR POSITION AND RESPONSIBILITIES?

A. I am Director of Pricing for the New England Gas Company ("NEGC" or the "Company"). My responsibilities include overseeing the design, implementation and administration of rates charged by the NEGC. I also direct the development of the Company's sales and revenue forecasts.

Q. WHAT IS YOUR PROFESSIONAL AND EDUCATIONAL BACKGROUND?

A. I was first employed by Providence Gas Company ("ProvGas") in January 1995 as a Pricing Analyst with responsibility for assisting in rate design, tariff administration and other regulatory activities. I was promoted to my current position in March 1998. I have previously testified in support of the currently effective Gas Cost Recovery ("GCR") rates in Docket No. 3436, in the ProvGas Gas Charge Clause ("GCC") filing in Docket No. 1673, the Valley Gas and Bristol & Warren ("Valley Gas") Purchased Gas Price Adjustment ("PGPA") filing in Docket No. 1736, in the NEGC Distribution Adjustment Charge ("DAC") filing in Docket No. 3459, in the NEGC rate case, Docket No. 3401, and in support of enhancements to the ProvGas Business Choice program in Docket No. 2902. I have also testified before the Massachusetts

Department of Telecommunications and Energy on behalf of North Attleboro Gas Company in Dockets D.T.E. 01-17 and D.T.E. 01-47.

Prior to joining NEGC, I was employed by NYNEX (now Verizon) for 24 years where I held various positions in the Regulatory, Government Relations and Marketing departments. While part of the Regulatory department at NYNEX, I prepared and filed testimony and testified in various dockets before the Rhode Island, Massachusetts and Vermont regulatory commissions on matters related to rate design, pricing and cost issues.

My educational background includes a Bachelor of Science degree in Electrical Engineering from Brown University. In addition, during my career at NYNEX, I completed a variety of business and management courses.

Q. **WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

A. The purpose of my testimony is to respond to an inquiry by the Commission relating to: (1) the Company's forecast of customer migration from firm sales to transportation service for the 2002-03 heating season; and (2) the impact of "reverse migration," or the migration of transportation customers to firm-sales service prior to the 2002-03 heating season (Docket 3436, Order No. 17444, at pages 24 and 25). Specifically my testimony will discuss the gas-requirements forecast underlying the base rates approved on May 23, 2002 in Docket 3401 and the Company's GCR filing approved initially on an interim basis on June 21 2002, and on a final basis on December 4,

2002. Lastly, my testimony will discuss policy options and possible tariff modifications that the Commission may wish to consider in addressing the gas-purchasing implications associated with customers migrating on and off of transportation service. The testimony of Mr. Gary Beland will provide a detailed analysis of the cost impact of reverse migration on the Company's overall cost of gas this past winter.

Q. DO YOU HAVE ANY EXHIBITS TO YOUR TESTIMONY?

A. Yes. I am sponsoring the following Exhibits:

PCC-1	Actual vs. Forecast Consumption
PCC-2	Calendar Degree Day Information
PCC-3	Summary of Transportation Migration
PCC-4	Analysis of Migration Activity

Q. PLEASE DESCRIBE THE PROCESS USED BY THE COMPANY TO FORECAST SALES-SERVICE REQUIREMENTS FOR THE ANNUAL GCR FILING IN JUNE 2002.

A. In the normal cycle of events, the Company prepares an annual forecast of gas consumption for use in conjunction with the Company's annual GCR filing. The typical forecasting process employed by the Company consists primarily of the following five steps:

1. <u>Compile Historical Consumption Data</u> – The Company first compiles the most recent actual customer and consumption information available;

2. Adjust Consumption Data for Known and Measurable Reductions – The Company then adjusts the actual data for any significant customer changes that would affect the Company's sendout requirements (e.g., the shut-down of the ongoing operations of a major customer);

3. Weather Normalization – The Company next normalizes the adjusted consumption data to account for the effect of weather;

4. Adjust Consumption Data for Forecasted Future Growth – The weather normalized data is adjusted to reflect growth in customer demands in order to determine projected sales;

5. Adjust Sales Forecast for the Effects of Transportation – The projected sales forecast is adjusted to account for load growth or load reductions associated with transportation throughput to determine the Company's total forecasted sales.

As noted above, the forecast used to developed the June 2002 GCR filing was also used to set base rates in Docket 3401. In Docket 3401, the forecast was carefully scrutinized through the discovery process to ensure that the level of throughput forecasted by the Company was reasonable.[1] For the purpose of setting base rates, the forecast was based on historical consumption data through September 2000 to coincide with the test-year period for the rate case. To project consumption through 2003, the historical consumption data was normalized and adjusted for growth in accordance with the Company's forecasting process. Because this forecast represented the first consolidated forecast for the combined Rhode Island operations, the Company also took into consideration the differing mix of sales and transportation customers and rate-class structures that existed between ProvGas and Valley Gas.

Q. PLEASE DESCRIBE THE HISTORICAL DATA USED IN STEP 1 TO DEVELOP THE COMPANY'S FORECAST.

A. To develop the forecast, the Company started its analysis with the actual number of customers and associated gas consumption on a monthly basis for the 12-month period October 1999 through September 2000 (the "2000 Data"). This data was described in the Docket 3401 testimony of Mr. Heintz (at pages 23 and 24) and shown in his Exhibit DAH-4.

Q. WERE ADJUSTMENTS MADE TO THE 2000 DATA TO ACCOUNT FOR KNOWN AND MEASURABLE CHANGES OCCURRING DURING THE TEST YEAR AND AFTER SEPTEMBER 2000?

A. Yes. Consistent with the Company's forecasting practice, the Company removed or adjusted data associated with customers in the Extra Large rate class who moved out

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1 The data requests relating to the development of the sales forecast in Docket 3401 were the following: DIV 1-81, DIV 3-3, DIV 3-4, DIV 3-5, DIV 3-6, DIV 5-19, DIV 5-20, DIV 7-21 and DIV 7-23.

of state, went out of business, or experienced a significant reduction in load as a result of changes in the nature or scope of their business during the test year or after September 2000. The Company also removed data associated with customers who switched from firm to non-firm service during the test year or after September 2000. Customers in the Extra Large rate class are the Company's largest customers with each account having annual consumption in excess of 15,000 Dth. Although there are less than 100 customers in this group, these customers account for approximately 12 percent of the Company's annual firm throughput. As a result, the Company's marketing group is generally familiar with these customers and their operations. The adjustments made to the 2000 Data were described in the Docket 3401 testimony of Mr. Heintz (at page 23) with additional details provided in the Company's response in Docket 3401 to Data Request DIV-7-21.

Q. PLEASE EXPLAIN HOW THE ADJUSTED HISTORICAL SALES DATA WAS NORMALIZED.

A. The historical consumption data for the period October 1999 through September 2000 (as adjusted for known changes) reflected a period that was warmer than the 10-year average. Normalization removed the effect of warmer-than-normal weather to provide consumption on a "normal" weather year. This computation was based on normal degree-days of 5,463 using a 10-year average ending September 2000.

To perform this computation, the Company first identified a base annual usage level by rate class using the average of the lowest usage months, <u>i.e.</u>, July through

September, because usage during this period is not related to heating load. The Company next subtracted the base usage from the actual usage to determine actual heating usage by month by rate class. The monthly heating usage was then divided by the actual billing degree-days in each month to calculate an average heat use per degree day. This average heat use per degree day was then multiplied by the normal monthly billing degree days to determine the normalized heating usage. The base usage was then added to this total to produce the normalized consumption levels.

Q. PLEASE DESCRIBE HOW THE WEATHER-NORMALIZED DATA WAS ADJUSTED TO ACCOUNT FOR FUTURE GROWTH.

A. After the weather-normalization adjustment, the rate-class consumption and customer counts were adjusted to account for projected growth between the end of the test-year period (12-months ending September 2000) and the end of the rate year (12-months ending June 2003). Using historical data and associated trends as well as input from the Company's marketing group, the Company developed individual customer-class growth rates, which were applied to the normalized gas-sales data described above.

Because ProvGas and Valley Gas had differing rate structures, forecasts of consumption growth were separately identified for the former Valley Gas and ProvGas customers. The Valley Gas forecast of the numbers of customers and the associated usage was transferred to the consolidated tariff rate classes based on percentages developed through an analysis of individual customer usage during the test period.

For example, 83 percent of customers and 26 percent of usage in the prior Valley Gas "Rate 80" class were allocated to the new consolidated "C&I Small" rate class.

Q. HOW DID THE COMPANY APPROACH THE FORECAST OF TRANSPORTATION MIGRATION GIVEN THE DIFFERING ELIGIBILITY REQUIREMENTS BETWEEN THE PROVGAS AND VALLEY GAS SYSTEMS?

A. Prior to the implementation of the consolidated statewide rate tariffs, transportation service on the Valley Gas system was restricted exclusively to its largest customers and, at the time, only 13 customers were taking transportation service. After the implementation of the consolidated tariff, 1,200 commercial and industrial ("C&I") customers gained eligibility for transportation service. As a result, it was necessary for the Company to estimate the level of migration that would occur once these customers became eligible for transportation service. The Company utilized two approaches in making this estimation: (1) the Company reviewed historical migration patterns and data on the ProvGas system; and (2) the Company performed a customer-by-customer analysis to assess the potential that the customers would migrate to transportation service.

On the ProvGas system, transportation service has been generally available to C&I customers for six years. As a result, the Company was able to draw on the ProvGas experience to analyze potential migration on the Valley Gas system for similarly situated customers. For example, C&I customers with relatively higher usage levels and higher than average load factors have the most options available to them in the marketplace and, for that reason, are generally the first to migrate to transportation service. These load characteristics are attractive to gas marketers who are able to capture economies of scale to reduce overall gas costs for these customers. More than 90 percent of the Extra Large customer class on the ProvGas system subscribes to transportation service. Within the Large and Medium C&I class on the ProvGas system, approximately 40 percent of the eligible customers take transportation services.

To estimate how this experience would translate in terms of migration on the Valley Gas system following a change in the customer-eligibility requirements, the Company performed a customer-by-customer analysis to assess the potential that the customers would migrate to transportation service. To accomplish this task, the Company's Marketing and Transportation groups reviewed a list of eligible customers on the Valley Gas system and identified individual customers who had the most potential to benefit from participation in the competitive marketplace. Based on the ProvGas experience, the Company estimated that all Extra Large and Large, High Load Factor customers would migrate to transportation service. All of these customers are large industrial customers with consistent consumption levels, which generally makes these customers extremely attractive to competitive gas marketers.

Of the remaining C&I customers, an individual customer assessment was made on the basis of the size, load factor and nature of the customer's business. For example, in the Providence area, the Company's experience was that the majority of housing authority accounts migrated to transportation service. Accordingly, the Company estimated that the 100+ Woonsocket and Pawtucket Housing Authority accounts would migrate to transportation service. Similarly, city and town accounts, schools, churches, restaurants as well as accounts of customers that had branch locations in Providence already on transportation service were estimated to migrate to transportation service.

Based on this analysis, the Company conservatively estimated that approximately one-third of C&I customers in the former Valley Gas service area, or 400 customers, would migrate to transportation service between September 2002 and November 2002 (Valley Gas customers were not eligible to start migrating from sales service until September 2002). Based on the long-term availability of transportation in the ProvGas service territory, the Company's forecast contemplated that the level of former ProvGas customers using transportation service would remain unchanged[2].

Q. HOW DID THE ACTUAL FIRM SALES AND TRANSPORTATION VOLUMES COMPARE TO THE FORECASTED AMOUNTS?

A. The Company's firm-sales consumption for the period July 2002 through the end of March 2003 was 23,890,000 Dth, or 12.8 percent higher than forecast. The firm

[2] Additional information and workpapers were provided in this docket on June 20, 2002 in response to the Division's data request DIV 1-01.

transportation consumption was approximately 10 percent below forecasted levels. The Company's total firm throughput (firm sales and transportation) was 29,450,000 Dth, which is 7.6 percent higher than the forecast of 27,365,000 Dth. A breakdown by customer rate class and a comparison of actual and forecasted consumption is provided on Exhibit PCC-1.

Q. TO WHAT DOES THE COMPANY ATTRIBUTE THE DIFFERENCE BETWEEN FORECASTED AND ACTUAL LEVELS OF FIRM SALES AND TRANSPORTATION SERVICE?

A. The Company believes that a number of factors contributed to the variance between actual and forecasted levels of firm throughput. By far the most significant factor affecting both sales and transportation consumption was the colder than normal weather that began in October 2002. Every month from October through March 2003 was colder than normal (11 percent colder over the period) leading to increased heating load and consumption. Applying the normalization routine described earlier in my testimony to actual consumption in the July 2002 through March 2003 period demonstrates that 2,198,000 Dth or 8 percent of increased consumption over the forecasted level was due to the colder-than-normal weather (see Exhibit PCC-1). This analysis indicates that the actual aggregate throughput, adjusted for weather, was within 1 percent of the forecast total throughput for the period.

Focusing only on sales-service volumes, the colder-than-normal weather accounted for 1,929,000 Dth or 70 percent of the difference between actual and forecast sales volumes. A summary of Calendar Degree-Day Information for FY 2003 is provided in Exhibit PCC-2.

Q. ARE THERE ANY OTHER FACTORS THAT PLAYED A ROLE IN THE VARIANCE BETWEEN TOTAL FORECASTED THROUGHPUT AND ACTUAL THROUGHPUT?

A. Yes, there are several factors that account for the variation between forecasted and actual throughput. One factor is simply the inherent ebb and flow that occurs anytime a forecast is involved in estimating actual experience in the future. There is continual variation in the number of customers taking sales service, the customer usage levels on sales service and the number of customers and amount of load migrating to and from transportation service. These variations often have offsetting effects and, over time, the Company's forecasting objective is to maintain overall consistency with actual experience, although any single component of the forecast may differ from that experience at any given time. A second factor was that, aside from the normal ebb and flow of customer load involved in the forecasting process, several of the large new loads projected at the time the forecast was prepared did not come on when expected. Since large customers are generally transportation customers, the overall impact of these delays was to cause a shortfall in the transportation throughput relative to the forecast, although there was no impact on sales-service volumes. There were other customers that went into bankruptcy and customers that moved all or part of their operations out of state. These two factors, in combination with the overall economic downturn, had a negative impact on actual throughput as compared to the forecast levels.

Q. DID THE COMPANY COMPARE ITS FORECAST LEVEL OF TRANSPORTATION SERVICE TO ACTUAL TRANSPORTATION VOLUMES DURING THE JULY 2002 THROUGH MARCH 2003 PERIOD?

A. Yes, in the winter period, the Company continually analyzes its forecast of transportation service volumes and actual customer consumption in order to maintain reliable service to firm sales customers. For this period, the Company examined customer migration from sales service to transportation service as well as the sales volumes that resulted from the unanticipated reverse migration from transportation service to sales service. The Company also studied new accounts that came onto the system starting as transportation service. From July 1, 2002 through February 28, 2003, there were a total of 150 customers that migrated from sales service to transportation service, 249 customers that switched from transportation service to sales service and another 4 customers that initiated gas service under the transportation service offerings. Exhibit PCC-3 provides a summary by month by rate classification.

Q. TO WHAT DOES THE COMPANY ATTRIBUTE THE LOWER-THAN-FORECASTED LEVELS OF TRANSPORTATION MIGRATION?

A. A variety of factors contributed to the lower-than-forecasted levels of transportation migration including the economic downturn and equity-market declines. However, the primary factor accounting for the downturn in customer migration was the significant shift that occurred in the gas marketing industry following the collapse of Enron during the winter season beginning November 2001. Many gas marketers came under increased government scrutiny for certain business and accounting practices, leading to much stricter credit reviews and additional scrutiny by regulators. As a result, many marketers reduced or eliminated their business activity and redefined or refocused their business plans. Marketing activity slowed substantially in a very short time period and many marketers decided not to pursue medium or single proprietor types of businesses in an effort to consolidate their overall financial and business operations. Although these changes began to take shape in early 2002, the effect of industry events on the business plans of local gas marketers did not become apparent until late summer and early Fall 2002, which is typically the time period in which gas marketers are most actively renewing contracts and recruiting customers.

Q. WHAT OPTIONS WERE AVAILABLE TO THE COMPANY TO AMELIORATE THE EFFECT OF THE LESS-THAN FORECASTED MIGRATION LEVELS ON THE VALLEY GAS SYSTEM?

A. As noted above, the changes in customer-eligibility requirements on the Valley Gas system did not become effective until September 2002. As a result, the earliest point at which the Company could have had an indication of the differences in forecasted and actual transportation would have been some time just prior to September 2002, which did not allow sufficient time for the Company to alter its gas-purchasing strategies to include additional load in the purchasing plan. However, even if the Company had been able to foresee that customer migration would be less than projected, the Company had little recourse to change the situation. The Company cannot force customers onto transportation service, and the availability of viable competitive options is not within the control of the Company. In addition, the landscape of the competitive retail gas marketplace changed significantly in a very short time period prior to the 2002-03 heating season. Therefore, the Company could not have reasonably anticipated these changes, or the effect that these changes would have, in developing its forecast for the GCR in June 2002.

At the direction of the Commission, the Company did undertake several initiatives to educate Valley Gas customers on the availability of transportation service prior to the implementation of the eligibility change in September 2002. For example, the Company gave a presentation to members of TEC-RI both before and after the implementation of the consolidated transportation tariff. The Company held a workshop for gas marketers to explain in detail the features and operation of the Company's transportation terms and conditions. In addition, the Company featured the implementation of the new tariff in its "Connections" publication mailed to all customers. However, the Company cannot unilaterally align actual experience with the forecast when the actions of third-party marketers are beyond the Company's control. As a result, the Company could neither alter its purchases under the gas-purchasing plan, nor have an affect on the availability of competitive options in the marketplace, and therefore, the Company had no opportunity to address the disparity between the forecasted and actual levels of transportation.

Q. DID CUSTOMERS ALSO MIGRATE FROM TRANSPORTATION SERVICE TO SALES SERVICE?

A. Yes, they did. Of the 249 customers that switched from transportation service to sales service, the vast majority (217 customers or 87 percent) were in the medium rate class and 83 percent of the switches occurred between July 1 and November 1, 2002. Customers in this group generally included small restaurants, some schools, apartment buildings, and various commercial accounts.

Q. HOW DID THE COMPANY HANDLE THE REVERSE MIGRATION?

A. The Company's transportation terms and conditions allow transportation customers to return to sales service with at least 30 days advance notice, subject to the availability of adequate gas transportation, gas supply and/or gas-storage capability. In addition, the returning customer is responsible for any incremental supply cost associated with the provision of sales service to the customer, as determined in the sole discretion of the Company.

In accordance with these provisions, the Company's response at the time the customers switched from transportation service to sales service was to allow the customers to do so at the then effective GCR rates. From the Company's vantage point, these customers were coming back to sales service based on the actions taken by the marketers (i.e., they were not trying to "game" the system). In addition, these customers were the smaller transportation customers whose level of consumption was relatively low as compared to the Company's total sales levels. Most importantly, at the time, market prices for gas were lower than the GCR rate. This meant that the Company was purchasing gas at a cost lower than the GCR to serve the returning customer, although the returning customer was paying the GCR rate. This produced a benefit for all sales customers for the first few months following the customers' return. Although this situation eventually "reversed," it was only because prices rose so dramatically during the winter of 2002-03, which the Company could not have reasonably foreseen at the time that these customers returned to sales service. At the point that these customers returned to sales service, all information available to the Company supported applying the GCR rate to these customers. Mr. Beland's testimony provides some additional information related to the market prices and the underlying GCR costs.

Q. HAS THE COMPANY ANALYZED THE IMPACT THAT THESE CUSTOMERS HAD ON THE SALES VOLUMES EXPERIENCED IN THE PERIOD JULY 2002 THROUGH MARCH 2003?

A. Yes. The Company identified each customer account that migrated from transportation service to sales service during the July 1, 2002 through February 28, 2003 period along with the specific timing of the change. Next the monthly consumption was identified and categorized as being sales service or transportation service and aggregated by rate class. The sales-service consumption associated with these customers from July 1, 2002 through March 31, 2003 was 311,065 Dth. This represents approximately 1.3 percent of total firm sales consumption during that period. Adjusting for the effects of colder than normal weather this past winter, the weather normalized sales service consumption of the reverse migration customers is approximately 280,000 Dth during the period, or 1.3 percent of total normalized sales. A detailed breakdown of the consumption by rate class by month is provided on Page 2 of Exhibit PCC-4.

Q. DOES THE COMPANY KNOW WHY THESE CUSTOMERS MIGRATED BACK TO SALES SERVICE?

A. The business environment for gas marketers described above has also had an effect on existing transportation customers. Based on discussions with a number of these customers as well as gas marketers, the majority of the customers that switched back to sales service did so because the customer's gas marketer decided not to renew the customer's contract. In the case of the one Extra Large account that switched to sales service, the customer was bought out by another company and was in the process of moving its operation to a different State.

Q. HAS THE COMPANY ANALYZED THE IMPACT OF THESE CUSTOMERS SWITCHING TO SALES SERVICE ON THE COST OF GAS FOR SALES SERVICE CUSTOMERS?

A. Yes. In response to a request from the Commission, the Company analyzed the variable costs of gas for returning customers this past winter along with the impact on the cost of gas the Company experienced this past winter. The analysis is discussed and provided in the testimony of the Company's witness, Mr. Beland.

Q. IF THE COMPANY WAS TO RECOVER THE INCREMENTAL COST OF THOSE VOLUMES IN NEXT YEAR'S GCR, WHAT WOULD BE THE IMPACT ON THE TYPICAL RESIDENTIAL HEATING CUSTOMER?

A. The typical residential heating customer's annual bill would be approximately $1.20 higher or approximately $0.10 per month. This is based on recovering the incremental cost associated with the reverse migration sales volumes, identified in Mr. Beland's testimony as being $329,000, over total annual sales volumes of approximately 27,000,000 dekatherms. A typical residential heating customer uses 100 dekatherms per year.

Q. WHAT WOULD BE THE IMPACT IF THE INCREMENTAL COST WERE RECOVERED JUST FROM THE CUSTOMERS MIGRATING BACK TO SALES SERVICE?

A. On average, each customer migrating back to sales service would have paid an incremental $2,300.

Q. WHAT ARE THE CURRENT TARIFF PROVISIONS THAT RELATE TO CUSTOMERS SWITCHING TO OR FROM SALES AND TRANSPORTATION SERVICE?

A. First, the tariff provides for two categories of firm 365-day transportation service. FT-1 Transportation service provides firm transportation of customer-purchased gas supplies to customers electing to have gas usage recorded on a daily basis and requires the customer to have a telemetering device on their gas meter. Migration from sales service to FT-1 service requires at least 30 days advance written notice. FT-2 transportation service allows a customer to purchase gas from a gas marketer without the requirement of recording daily gas usage. The customer's meter continues to be read once per month similar to sales service customers. Migration from sales service to FT-2 service requires at least 15 days advance written notice. The tariff allows customers to return to sales service with at least 30 days advance notice, subject to availability, in the Company's sole discretion, of adequate gas transmission, gas supply and/or gas storage capability, and subject to the incremental supply cost, in the Company's sole discretion, associated with providing such sales service. In the case of a gas marketer terminating service to a customer, the marketer is required to provide the Company with 30 days advance notice.

Q. ARE THERE ANY CASES WHERE TRANSPORTATION CUSTOMERS ARE NOT ALLOWED TO COME BACK TO SALES SERVICE?

A. Yes. Any C&I customer account classified as Large or Extra Large that subscribes to FT-1 transportation service and that does not have Company provided pipeline capacity assigned to their marketer is prohibited from switching to the Company's firm sales service. These customers are required to take default transportation service, where a Company-selected third party gas marketer has agreed to provide separate service to the customer. In such situations, the Company's supply portfolio and resources are not used to meet the customer's needs.

Q. GIVEN THE RECENT EXPERIENCE WITH REVERSE MIGRATION AND THE COLDER THAN NORMAL WINTER, HAS THE COMPANY DEVELOPED ANY PROPOSED CHANGES TO ITS TARIFF?

A. Yes, the Company is currently considering a possible modification to the transportation tariff to address the cost impacts of reverse migration. Although it could be beneficial to allow another heating season to pass so that additional experience could be gained to guide the development of a tariff provision, it is the Company's objective to minimize any cost impact on existing firm sales customers resulting from transportation customers re-migrating to sales service. Because the reverse migration loads are not factored into the Company's Gas Purchasing Plan (GPP), "reverse-migration" customers have the potential to affect the overall costs that the system incurs to provide sales service during the heating season (both negatively and positively). As a result, to the extent that the policy decision is made to isolate the effects of this reverse migration from the sales service portfolio, the cost of serving reverse migrating customers needs to be separately identified and recovered from those customers outside of the sales-service framework.

Thus, the Company is considering the development of a monthly surcharge mechanism to apply to those customers who migrate from transportation service to sales service. Under the Company's proposal, the reverse-migration customers would be charged the currently effective GCR rate, subject to a tariffed surcharge rate. This surcharge would be designed to charge a market-based price reflecting the cost of gas supplies in the marketplace at the time consumption is occurring for the incremental amount of gas that the Company must buy outside of the GPP. The surcharge calculation would involve a four-step process. First, the Company would obtain the average NYMEX closing price (available 3 business days prior to start of month). Second, the Company would calculate the average cost of gas purchased under the GPP for the same month. Next the difference of the marketplace price and the GPP price would be adjusted to reflect the percentage of gas supplies purchased outside of the GPP (because not all sales service volumes are subject to the GPP). Lastly, the Company would eliminate from the surcharge the average cost per/dth of the deferred fuel cost balance embedded in the GCR (plus or minus) because the deferred fuel cost balance existing at the time the reverse migration occurs would not relate to these customers. Therefore, the surcharge would equal the NYMEX cost of gas less the embedded cost of gas purchased under the GPP adjusted to reflect the percentage of gas supplies purchased outside of the GPP and less the unit cost of the deferred fuel balance existing at the time of the reverse migration. The Company would apply the surcharge to all volumes consumed by reverse-migration customers in the period September 1st through April 30th of each year. As of April 30th of each year, any customers who have returned to sales service since September 1 and are subject to the surcharge would become sales-service customers so that the surcharge would no longer apply. Going forward, the customer would either remain a sales-service customer and be included in the GPP, or the customer could elect to migrate to transportation service, at which point the customer's load becomes part of the Company's forecasted transportation migration, which is excluded from the GPP. This process serves to ensure that existing sales service customer receive the full benefit of the GPP and that customers who migrate from transportation service to sales service are not treated any differently than other sales customers beyond the period in which the migration of their volumes to sales service could affect the price of gas to all sales customers. In addition, this approach is administratively feasible for the Company. Lastly, this approach does not create any barriers to competition, which would occur if a tariff change were made to either require a customer to stay on sales service for some period after returning to sale service, or to permanently exclude the customer from the GPP were they to return to sales service.

Q. IS THE COMPANY DEVELOPING A TARIFF TO IMPLEMENT THIS PROPOSAL?

A. Yes. Based on the Company's analysis and consideration of various alternatives to deal with this issue, the Company is currently developing a tariff to implement the proposed surcharge discussed above. The Company will review this tariff with the Division and will file the tariff with the Commission as soon as possible.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

GAS COST RECOVERY FILING
FORECASTED vs. ACTUAL THROUGHPUT (Dth)
July 2002 through March 2003

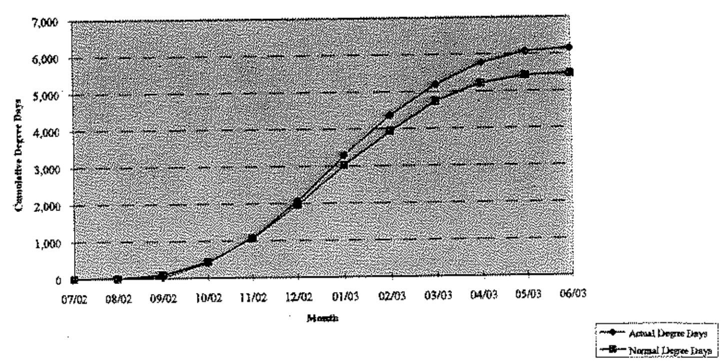
Line No.	Rate Class (a)	Forecast (b)	Actual (c)	Difference (d) = (c)-(b)	Normalized Actual (e)	Difference (f) = (e)-(b)
1	**SALES (dth)**					
2	Residential Non-Heating	600,050	538,651	(61,399)	521,040	(79,010)
3	Residential Heating	14,681,237	16,082,439	1,401,202	14,691,678	10,441
4	Small C&I	2,137,978	2,472,707	334,730	2,258,158	120,180
5	Medium C&I	2,677,038	3,238,662	561,624	3,030,654	353,616
6	Large LLF	774,608	833,204	58,597	763,057	(11,551)
7	Large HLF	155,439	373,374	217,935	360,753	205,315
8	Extra Large LLF	37,490	141,664	104,173	131,730	94,240
9	Extra Large HLF	112,809	213,748	100,939	208,259	95,451
10	**Total Sales**	21,176,648	23,894,448	2,717,800	21,965,328	788,681
11	**FT-2 TRANSPORTATION**					
12	FT-2 Medium	602,028	443,858	(158,171)	410,705	(191,323)
13	FT-2 Large LLF	136,037	102,688	(33,349)	94,829	(41,208)
14	FT-2 Large HLF	35,043	51,391	16,348	50,169	15,126
15	FT-2 Extra Large LLF	0	3,259	3,259	3,188	3,188
16	FT-2 Extra Large HLF	1,128	0	(1,128)	0	(1,128)
17	**Total Transportation**	774,237	601,195	(173,041)	558,891	(215,345)
18	**FT-1 TRANSPORTATION**					
19	FT-1 Medium	1,061,878	801,928	(259,949)	755,002	(306,875)
20	FT-1 Large LLF	900,115	920,255	20,140	854,846	(45,269)
21	FT-1 Large HLF	635,448	456,738	(178,710)	442,765	(192,683)
22	FT-1 Extra Large LLF	672,090	463,774	(208,315)	428,288	(243,802)
23	FT-1 Extra Large HLF	2,145,056	2,309,748	164,691	2,245,290	100,234
24	**Total Transportation**	5,414,587	4,952,443	(462,144)	4,726,192	(688,395)
25	**Total THROUGHPUT**					
26	Residential Non-Heating	600,050	538,651	(61,399)	521,040	(79,010)
27	Residential Heating	14,681,237	16,082,439	1,401,202	14,691,678	10,441
28	Small C&I	2,137,978	2,472,707	334,730	2,258,158	120,180
29	Medium C&I	4,340,944	4,484,448	143,504	4,196,361	(144,582)
30	Large LLF	1,810,759	1,856,147	45,388	1,712,731	(98,028)
31	Large HLF	825,930	881,503	55,573	853,687	27,758
32	Extra Large LLF	709,580	608,697	(100,883)	563,206	(146,374)
33	Extra Large HLF	2,258,993	2,523,495	264,502	2,453,549	194,556
34	**Total Throughput**	27,365,471	29,448,086	2,082,616	27,250,411	(115,060)

CALENDAR DEGREE DAY INFORMATION 2002-03

ACT/FCST AVG	0	0	1	13	22	32	40	39	26	19	10	3
DAY	JULY	AUG	SEPT	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUNE
1	0	0	3	0	21	33	24	31	36	30	13	7
2	0	0	0	0	29	34	32	28	26	21	4	4
3	0	0	0	0	29	40	33	23	41	25	10	4
4	0	0	0	3	25	42	31	23	44	31	13	9
5	0	0	0	0	22	41	36	35	27	31	15	7
6	0	0	0	8	19	36	37	40	36	27	14	0
7	0	0	0	3	28	40	42	39	46	32	3	6
8	0	0	0	11	21	30	35	45	31	33	14	1
9	0	0	0	14	10	43	26	38	29	30	8	5
10	0	0	0	9	5	37	31	36	44	24	8	0
11	0	0	0	8	1	34	38	42	39	26	9	0
12	0	0	3	6	11	28	35	42	23	13	11	0
13	0	0	0	6	18	29	35	53	33	16	9	5
14	0	0	0	15	20	21	43	52	40	20	7	0
15	0	0	0	19	13	24	42	53	30	4	8	0
16	0	0	0	8	23	32	42	55	18	0	16	7
17	0	0	0	11	23	39	42	44	14	29	15	7
18	0	0	0	16	24	36	54	41	18	24	12	6
19	0	0	0	15	28	31	48	37	30	18	3	0
20	0	0	0	14	21	14	40	28	28	15	6	0
21	0	0	0	17	23	25	48	27	14	15	8	2
22	0	0	0	21	18	23	51	28	8	19	13	7
23	0	0	0	24	25	26	54	30	17	17	15	0
24	0	0	2	22	25	28	46	35	19	20	15	0
25	0	0	0	21	24	30	42	43	25	19	12	0
26	0	0	3	16	22	32	35	51	13	15	15	0
27	0	0	0	13	34	34	46	44	14	9	10	0
28	0	0	0	19	41	34	54	37	17	6	6	0
29	0	0	7	25	34	31	40		9	1	1	0
30	0	0	5	25	22	34	38		20	10	2	0
31	0	2		23		23	31		29		2	
ACT/FCST	0	2	23	392	659	984	1,231	1,080	818	580	297	77
NORMAL	1	1	92	345	625	892	1,073	914	798	476	208	38
DIFF	(1)	1	(69)	47	34	92	158	166	20	104	89	39
% DIFF.	-100.00%	100.00%	-75.00%	13.62%	5.44%	10.31%	14.73%	18.16%	2.51%	21.85%	42.79%	102.63%
CUM DIFF.	-1	0	-69	-22	12	104	262	428	448	552	641	680
CUM %	-100.00%	0.00%	-73.40%	-5.01%	1.13%	5.32%	8.65%	10.85%	9.45%	10.58%	11.82%	12.45%

FISCAL 03 ACT/FCST	6,143	
FISCAL 03 NORMAL	5,463	680
FORECASTED % DIFFERENCE	12.45%	

NOTE:
SHADED AREA REPRESENTS A PROJECTION OF DEGREE DAYS BY THE WEATHER SERVICES CORPORATION AS OF JUNE 26, 2003



Summary of Migration To / From Transportation Service

	Jul-02	Aug-02	Sep-02	Oct-02	Nov-02	Dec-02	Jan-03	Feb-03	Total
A. Number of firm customers migrating from sales to transportation service.	21	3	10	10	28	34	31	13	**150**
B. Number of firm customers migrating from transportation service to sales service.	16	18	106	23	45	6	8	27	**249**
C. Number of new firm transportation customers.	0	0	0	2	1	0	0	1	**4**

	Jul-02	Aug-02	Sep-02	Oct-02	Nov-02	Dec-02	Jan-03	Feb-03	Total
A's: Sales-to-Transp									
Medium	13	2	10	9	26	29	29	12	130
Large	8	1	0	1	1	5	2	1	19
Extra Large	0	0	0	0	1	0	0	0	1
sub-total A's	21	3	10	10	28	34	31	13	150
B's: Transp-to-Sales									
Medium	14	17	100	19	38	3	6	20	217
Large	2	1	6	4	7	3	2	6	31
Extra Large	0	0	0	0	0	0	0	1	1
sub-total B's	16	18	106	23	45	6	8	27	249
C's: New Transportation Customers									
Medium	0	0	0	0	0	0	0	0	0
Large	0	0	0	1	0	0	0	0	1
Extra Large	0	0	0	1	1	0	0	1	3
sub-total C's	0	0	0	2	1	0	0	1	4

Analysis of Migration Activity

The following is a summary of customer migration during the Period July 2002 through February 2003

Migration from Transportation to Sales

note: includes 26 accounts that switched back to transportation during this period

	C&L Medium	C&L Large	C&L X-Large	Total
Customers	**217**	**31**	**1**	**249**
Actual Consumption Jul 02 - Mar 03 (Dth)	267,073	158,309	12,551	**437,934**
Transportation Portion	71,653	42,794	12,423	126,869
Sales Portion	195,421	115,515	128	311,065
Normal Consumption Jul 02 - Mar 03 (Dth)	247,167	145,180	12,551	**404,899**
Transportation Portion	69,851	42,852	12,423	125,125
Sales Portion	177,317	102,328	128	279,774

Migration from Sales to Transportation

	C&L Medium	C&L Large	C&L X-Large	Total
Customers	**130**	**19**	**1**	**150**
Actual Consumption Jul 02 - Mar 03 (Dth)	184,085	76,769	29,275	**290,129**
Transportation Portion	143,017	65,989	21,967	230,973
Sales Portion	41,069	10,780	7,309	59,157
Normal Consumption Jul 02 - Mar 03 (Dth)	170,927	74,469	27,458	**272,854**
Transportation Portion	131,481	63,833	19,812	215,126
Sales Portion	39,446	10,636	7,646	57,728

Analysis of Migration Activity

Rhode Island	Mar-03 Dth	Feb-03 Dth	Jan-03 Dth	Dec-02 Dth	Nov-02 Dth	Oct-02 Dth	Sep-02 Dth	Aug-02 Dth	Jul-02 Dth	TOTAL
Actual Billed Consumption										
Customers Who Switched From Transportation to Sales - Sales Consumption										
FT-1 Medium	20,185	23,161	25,519	19,203	12,533	7,923	2,125	0	0	110,649
FT-2 Medium	19,417	20,823	17,111	14,344	7,827	3,441	1,225	305	278	84,772
FT-1 LLF Large	18,858	12,975	13,259	12,174	8,794	1,544	890	0	0	68,494
FT-2 LLF Large	6,792	8,738	8,788	7,706	4,247	197	21	0	0	36,489
FT-1 LLH Large	1,542	1,542	1,360	1,021	659	645	604	604	604	8,580
FT-2 LLH Large	1,010	943	0	0	0	0	0	0	0	1,953
FT-1 LLH X-Large	128	0	0	0	0	0	0	0	0	128
Sub Total	67,933	68,183	66,037	54,449	34,059	13,750	4,864	909	881	**311,065**
Customers Who Switched From Transportation to Sales - Transportation Consumption										
(includes consumption of customers who switched from transportation to sales and back to transportation)										
FT-1 Medium	3,946	3,706	5,090	5,034	3,459	3,140	1,378	5,580	6,319	37,653
FT-2 Medium	2,062	4,712	5,557	3,753	4,101	3,817	2,813	3,924	3,261	34,000
FT-1 LLF Large	1,568	2,256	8,079	7,168	4,213	5,209	1,045	1,738	1,259	32,536
FT-2 LLF Large	0	0	0	0	525	1,689	51	60	405	2,730
FT-1 LLH Large	0	0	0	318	308	783	38	34	40	1,521
FT-2 LLH Large	0	0	1,154	628	1,250	1,105	1,084	285	500	6,007
FT-1 LLH X-Large	0	2,316	1,750	2,351	1,263	1,148	1,312	1,250	1,032	12,423
Sub Total	7,576	12,990	21,630	19,251	15,120	16,892	7,721	12,872	12,817	**126,869**
Customers Who Switched From Sales to Transportation - Sales Consumption										
FT-1 Medium	0	0	198	5,018	7,123	4,903	3,012	1,864	2,376	24,495
FT-2 Medium	0	0	326	2,706	3,364	3,035	2,336	2,139	2,666	16,573
FT-1 LLF Large	0	0	0	0	0	837	737	677	725	2,977
FT-2 LLF Large	0	0	0	0	518	390	5	27	0	940
FT-1 LLH Large	0	0	128	679	823	857	714	786	704	4,691
FT-2 LLH Large	0	0	0	495	449	246	254	385	343	2,172
FT-1 LLH X-Large	0	0	0	0	3,754	2,713	459	0	382	7,309
Sub Total	0	0	652	8,897	16,032	12,982	7,517	5,879	7,196	**59,157**
Customers Who Switched From Sales to Transportation - Transportation Consumption										
FT-1 Medium	18,906	23,046	30,248	14,277	5,321	3,091	1,640	1,542	1,526	99,597
FT-2 Medium	10,210	12,085	10,136	5,389	3,284	1,252	455	466	142	43,420
FT-1 LLF Large	6,343	8,849	9,741	8,653	5,640	2,918	846	994	998	44,982
FT-2 LLF Large	1,239	2,019	2,387	1,508	346	196	155	307	3	8,159
FT-1 LLH Large	1,959	1,784	1,586	965	839	895	273	921	781	10,005
FT-2 LLH Large	812	812	591	626	0	0	0	0	0	2,843
FT-1 LLH X-Large	3,909	5,547	7,301	5,210	0	0	0	0	0	21,967
Sub Total	43,378	54,143	61,991	36,628	15,430	8,353	3,369	4,230	3,450	**230,973**
										728,063
Total Sales Consumption	67,933	68,183	66,689	63,346	50,091	26,733	12,381	6,788	8,078	370,221
Total Transportation Consumption	50,955	67,133	83,620	55,880	30,551	25,245	11,090	17,102	16,267	357,842

STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS

PUBLIC UTILITIES COMMISSION

NEW ENGLAND GAS COMPANY

DOCKET NO. 3436

DIRECT TESTIMONY

OF

GARY L. BELAND

June 26, 2003

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Gary L. Beland, and my business address is 100 Weybosset Street, Providence, Rhode Island 02903.

Q. WHAT ARE YOUR POSITION AND RESPONSIBILITIES?

A. I am Director of Gas Supply for New England Gas Company ("NEG" or the "Company"). My responsibilities include all aspects of gas supply management including purchasing, contracting, planning, Federal regulatory monitoring and intervention, and system monitoring and control.

Q. WHAT IS YOUR BACKGROUND AND EXPERIENCE?

A. I began my career in the gas industry in June of 1977 as an analyst in the Rates and Regulatory Affairs Department of Michigan Consolidated Gas (MichCon) after receiving my MBA from the State University of New York of Albany. At MichCon, I worked on a variety of projects and studies including pipeline rate filings, state rate cases, demand modeling, gas-supply cost simulations, conservation planning and strategic analyses.

In 1983, I was hired by Niagara Mohawk as a Corporate Planner. In that position, I was responsible for strategic analysis and a variety of projects in integrated resource planning, pipeline regulatory monitoring and intervention, both end-use based and econometric electric and gas demand forecasting, fuel cost forecasting and modeling and gas market unbundling. In 1987, I joined the newly formed gas business unit as Manager of Gas Supply Planning. While I was at Niagara Mohawk, I was involved in the Forecasting and Planning Sub-committee of the New York Power Pool and the Planning Committee of the New York Gas Group, serving as chairman at the time I left to join the Providence Gas Company ("ProvGas") in 1994. I have testified in several dockets before the Federal Energy Regulatory Commission. I have also testified on market forecasts, both gas and electric and a gas-cost incentive mechanism before the New York Public Service Commission.

I joined ProvGas in 1994 as the Manager of Gas Supply. In 1997, I became Assistant Vice President. After the merger with Southern Union Company, I was named Director of Gas Supply for the New England Gas Company.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to provide a detailed analysis of the impact on the Company's cost of gas during the winter of 2002-2003 resulting from the migration of transportation customers to sales service in the period July 1, 2002 through March 31, 2003. This analysis is shown in Exhibits GLB-1 through GLB-4.

Q. WOULD YOU FIRST PROVIDE AN OVERVIEW OF HOW THE COMPANY PURCHASES GAS SUPPLY?

A. The Company's gas purchases are largely a function of the type of capacity resources that the Company has under contract in the resource portfolio. Each of these contracts sources gas from a specific location and each contract sets out the receipt and delivery points available to the Company to meet its gas-supply needs. For example, a long-haul transportation contract may have many receipt points throughout the Gulf of Mexico supply area, or may have limited receipt points on another pipeline. In addition, the Company's gas purchases may depend upon where the supply is needed in terms of the two interstate pipelines that serve the Company (i.e., the Tennessee Gas Pipeline Company or Algonquin Gas Transmission Company).

Purchases are made by determining the supply option that will reach the gas system at the lowest cost based on the various opportunities available to purchase supply where both pipeline capacity and gas supply exist. Each point where the supply is purchased may carry a different price based on the pipeline and the area or sub-area where the supply is located. In some cases the Company may purchase supply based on a published index that is stipulated by a supply contract that entitles the Company to the supply at that certain published price and obligates the supplier to deliver. At other times the supply is obtained by calling a number of suppliers to obtain the best bid.

The largest portion of gas supply needed to meet winter heating season requirements is purchased under the gas purchasing plan by locking the NYMEX-Henry Hub portion of the price and leaving the locational basis, or the difference between the NYMEX price at Henry Hub in Louisiana and the relevant published index, to be determined by the actual basis at the close of the NYMEX contract 3 business days prior to the start of the month for which the purchase is made. This is a convenient and inexpensive way to hedge a substantial amount of supply purchases and within this hedging framework, supply is still purchased in a way that the supplies originating from the lowest cost supply areas are scheduled ahead of more costly supplies. However, it is only practical to hedge quantities of supply that are actually needed and weather and variations in load such as weekday/weekend swings don't allow for all purchases to be made at a uniform daily amount for the month. Some of the swing is absorbed by storage, either pipeline based storage through injection or withdrawal, or through peaking supplies such as LNG or LPG. Storage is filled in the warm months of April to October and withdrawn in the colder months of November to March.

The remaining swing requirements are met through shorter-term purchases, often made outside the Gulf supply area in places such as Lambertville, NJ where the Texas Eastern Pipeline feeds the Algonquin pipeline or Dracut, MA, where the Maritimes and Northeast Pipeline delivers gas from Eastern Canada into the Tennessee pipeline system. Some supply is also purchased right at citygate, which is the delivery point into the local gas distribution system. Because of the restrictions that sometimes occur on pipelines, those supplies can be unreliable and are often used only to serve interruptible sales customers or to reduce costs by displacing a higher cost supply such as LNG or propane.

Q. HOW DOES THE COMPANY GENERALLY DETERMINE THE COST OF GAS FOR SALES CUSTOMERS?

A. The cost of gas is determined by adding up all expenditures for supply, pipeline capacity and other direct supply costs to arrive at the cost of gas for the month. The cost of storage supplies is based on the average cost of inventory in the storage area from which the supply is drawn. Under the Gas Purchasing Plan in place for sales service customers, the cost includes the mandatory and discretionary purchases made under the plan.

Q. WOULD YOU PLEASE EXPLAIN HOW YOU APPROACHED THE ANALYSIS TO DETERMINE THE EFFECT THAT REVERSE MIGRATION CUSTOMERS HAD ON THE COST OF GAS FOR SALES SERVICE CUSTOMERS?

A. Yes. From an overall perspective, the Company has constructed a direct comparison between the actual cost of gas to serve firm sales customers and the estimate of the cost of gas to serve customers who migrated from transportation to sales service. To the extent possible, the analysis is based on actual costs to estimate the cost impact.

As discussed above, aside from the GPP, gas costs are determined largely by the capacity resources available to source gas from the supply regions. A major feature of the Company's transportation program is that customers who migrate to and from transportation service carry with them a pro rata allocation of the pipeline capacity that is necessary to meet their load requirements. If customers migrate to transportation service, the assignment of a pro rata share of the Company's pipeline capacity resources prevents sales customers from having to bear the burden of paying for resources that were procured to serve customers that elect to take gas supply from a third-party marketer. If these customers migrate back to sales service, the capacity that was previously assigned to their marketer on their behalf, returns to the Company portfolio and is then available to serve those customers. In determining the cost impact that reverse migration customers had on the cost of gas to sales service, the fact that they return with capacity resources is important. The assigned pipeline capacity provides the transportation capability for the supply and determines the location where the gas will be purchased. Because supply cost varies based on location, the capacity essentially determines the cost of the supply itself. For the purpose of the analysis, it should be noted that FT-1 customers bring with them the pipeline capacity resources, while FT-2 customers also bring with them the storage and peaking supply capability necessary to meet their load requirements.

As a result, in the analysis of the cost of gas for customers who migrated back to sales service, the returning resources were sufficient to serve over 94% of the load of the re-migrating customers.

By using the supply resources that returned from assignment to determine supply sourcing, it is possible to closely simulate the supply cost of the customers migrating back to sales service each month. Comparing that cost to the average cost for firm sales customers enabled the Company to determine the degree to which the migrating customers increased (or decreased) the gas costs of other firm sales customers. This cost is calculated as a unit cost (Exhibit GLB-1, line 12) and is compared with the actual unit cost of gas supply incurred each month to serve all firm sales customers (Exhibit GLB-1, line 13). The difference between the two is how much more or less it cost per dekatherm to serve the customers returning from transportation service versus the firm sales customers. The difference (line 14) in unit cost is then multiplied by the quantity sold (line 11) to returning customers to yield the total additional cost of $328,784, which is shown on line 15 of Exhibit GLB-1.

As discussed in the testimony of Mr. Czekanski, this cost analysis is based on the monthly volumes of gas actually used by returning customers (see, Exhibit PCC-4, at page 2 of 2). The analysis is calculated based on the total sales billed to returning customers in each individual month as these customers returned to sales service during the July 2002 to March 2003 period.

Q. DID THE COMPANY ALSO INCUR ADDITIONAL PIPELINE CAPACITY COSTS TO SERVE REVERSE MIGRATING CUSTOMERS?

A. The demand charges for both sales customers and transportation customers migrating back to sales service are included in the analysis.

Q. COULD YOU PROVIDE MORE DETAIL ON THE CALCULATION OF THE COST OF GAS FOR REVERSE MIGRATING FT-1 CUSTOMERS AS SHOWN IN EXHIBIT GLB-2.

A Exhibit GLB-2, line 1 shows the pipeline capacity returned as a result of all FT-1 reverse migration. This is obtained from summing the mandatory assignment quantities for the customers who reverse migrated month-by-month. Line 2 shows the actual sales made each month to the reverse migrating customers. This amount is then broken into two pieces. The first, line 3, represents the amount of the reverse migrating load that could be met using the assigned pipeline capacity that was returned when the customers reverse migrated. The second, line 4, is the requirements above that level.

The next section shows the commodity cost per dekatherm of the supply delivered using returned capacity. Approximately 90 percent of all capacity released to marketers is long haul pipeline capacity originating in the Gulf of Mexico production area. This capacity accesses supply that is less expensive, particularly in the winter. Since the lowest cost supply would be used first, this supply is assumed in the analysis to be used ahead of other supply options. The analysis also assumes that it is Tennessee Pipeline capacity from Zone 1 and priced at the first-of-the-month index (line 5). This assumption simplifies the analysis and reflects the fact that Tennessee capacity is a significant portion of the capacity released under the assignment program and very close in price to the system weighted average. The assumption of first-of-the month pricing is consistent with the way long haul supplies are managed, particularly in the winter.

The remaining 10 percent of returning pipeline capacity is assumed to be Algonquin capacity originating in Lambertville, New Jersey and is assumed to be purchased day-to-day, as needed. The pricing (line 6) of this short haul supply provided by this capacity is based on its market price each day. To keep the analysis simple this price is blended (line 7) with the price of the Tennessee supply. The Algonquin capacity is about 10 percent of all assigned capacity and is the only short haul capacity (i.e., capacity beginning in the mid-Atlantic states, in this case, rather than in the Gulf) currently being assigned to marketers under the assignment program.

The last commodity cost (line 8) is the incremental cost or highest cost gas each day. Because the FT-1 customers do not receive storage or LNG service under the capacity assignment program as FT-2 customers do, the supply to serve them is effectively the last supply dispatched, assumed here to be the highest cost supply purchased or, in the case of peaking supplies, produced each day. In some instances this approach is conservative because the price of certain contracted-for gas supplies would have resulted in an index-based market price even absent the load added by these customers, but use of this conservative approach guarantees the analysis incorporates the maximum effect of reverse migration on the cost of sales service.

Line 11 in the Exhibit shows the commodity cost of supplying reverse migrating customers. The commodity cost is the product of the sales times the commodity price. Similarly, the fixed cost of the pipeline capacity returned is calculated in the next section. The calculation is also based on the assumption that 90 percent of the capacity is Tennessee Zone 1, which carries a demand charge of $15.22 per dekatherm, per month of service, and 10 percent is Algonquin, which is priced at capacity at $6.59/Dt/month. Adding together the commodity and demand costs yields the total estimated cost of supplying the actual monthly volumes used by the reverse migrating customers. This amount is carried over to Exhibit GLB-1 along with the sales quantity.

Q. COULD YOU PROVIDE MORE DETAIL ON THE CALCULATION OF THE COST OF GAS FOR FT-2 CUSTOMERS WHO REVERSE MIGRATED AS SHOWN IN EXHIBIT GLB-3.

A. The calculation for the FT-2 customers is very similar to the FT-1 customers, but with one major difference. When these customers return, they bring back storage and peaking capability in addition to pipeline capacity, which FT-1 customers do not. As a result, it is not necessary to obtain incremental supplies at relatively high cost to serve these FT-2 customers. Even in a very cold winter the resources should be adequate to meet their needs because the resources assigned to these customers are based on design weather conditions. Where weather is warmer than design, some amount of excess resources would be available to meet the needs of other firm sales customers.

Q. BASED ON YOUR ANALYSIS, WHAT WAS THE IMPACT OF REVERSE MIGRATION ON GAS SUPPLY?

A. Exhibit GLB-4 shows the impact of the actual reverse migration volumes. Over the nine-month period sales to reverse migrating transportation customers were 1.2 percent of firm sales sendout and 1.4 percent of total gas cost. The increase in cost caused by the remigration, \$328,784 (GLB-1, line 15), represents an increase in total gas cost for firm sales customers of 0.2%, equal to 1.2 cents per dekatherm. The impact on the Company's capacity requirements was almost entirely offset by the returning assigned pipeline and other capacity resources.

Q. AT THE TIME OF THE MIGRATION BACK TO SALES SERVICE, WHAT WAS THE EXPECTED IMPACT ON GAS COSTS?

A. Current and future gas prices at the time that the bulk of the migration was occurring were very similar to those included in the GCR filing. For example, the NYMEX closing prices in July, August, and September were all below the level used in the GCR filing that went into effect July and the closing prices in October, November and December averaged less than 20 cents above the GCR level. Gas commodity prices frequently fluctuate by more than 20 cents in a day. As a result, market prices were in the range of the prices being paid by the customer migrating back from transportation through the GCR. Exhibit GLB-5 shows the prices in the GCR and the forward price curve on the date of each contract close over the July 2002 to March 2003 period. The graph in GLB-5 shows that the prices were below or near to the prices in the GCR until the January close on December 27th. It also shows that the prices locked under the purchasing plan were also in the same range.

Moreover, prices did not escalate significantly until December 2002, at which point 86 percent of the reverse migration had already occurred. Exhibit GLB-1 shows the difference between the average cost of gas sold to firm sales customers and the cost incurred to serve the reverse migrating customers and clearly shows that most reverse migration occurred well before prices escalated. In the months of July, August, September, and October, gas costs for the reverse migrating customers were less than that for other firm sales customers and in the months of November and December the supply cost difference was $0.13 and $0.05, a difference of 2.5 percent and 1 percent, respectively.

Q. WHAT FACTORS INFLUENCED THE INCREASE IN GAS COSTS OVER THE WINTER PERIOD?

A. In the middle of the summer, storage was unusually full, prices had moderated and there were a number of reasons to be optimistic about prices. Prices did move up following two hurricanes that moved through the Gulf production area causing damage to a number of off-shore production facilities and a spell of exceptionally hot weather in the Northeast and Midwest caused gas use for electric generation to increase sharply. These temporary short-term events caused some increase in prices, but only up to levels comparable to those in the GCR. Prices did not foreshadow the escalation that began in late December but only really peaked in late February. Seventy-three percent of the $328,000 cost increase was caused by the transportation customers who returned to sales service occurred in March alone.

Q. GIVEN THE OPERATION OF THE MANDATORY CAPACITY ASSIGNMENT PROGRAM IS THERE A NEED TO TAKE FURTHER ACTION TO LIMIT THE IMPACT OF MIGRATION TO AND FROM SALES SERVICE BY TRANSPORTATION CUSTOMERS?

Q. Although the fact that FT-1 and FT-2 customers return to sales service with the capacity resources necessary to meet their load requirements largely mitigates the cost impact that could occur with the return of these customers to sales service, the results of the Company's analysis indicate that an additional change may be appropriate. An examination of Exhibit GLB-1 and the monthly results at the bottom of the exhibit indicates that in certain instances it can be substantially more expensive to serve reverse migrating customers (i.e., where prices are exceptionally high such as March 2003). This difference in price appears to be primarily the result of the benefits provided by the Company's gas purchasing plan, which permits the Company generally to dollar-cost-average its gas supply requirements which helps to moderate gas price volatility.

Currently, there is no mechanism in place to circumscribe the benefits of the Company's gas purchasing program to the Company's sales customers. It is also possible that sales service customers could be harmed when hedging purchases are made after transportation customers have reverse migrated to sales and those purchases ultimately turn out to be above market.

A second consideration is the impact of the incremental daily or short term purchases necessary to serve that portion of the FT-1 requirements not covered by assigned capacity and storage. Under normal circumstances, including weather that is reasonably close to normal (or warmer than normal), the reliance on daily purchases at regional supply points to serve reverse migrating customers is likely to result in *lower* gas costs, not higher.

Q. IS THE COMPANY MAKING A PROPOSAL TO DEAL WITH THE COST IMPACTS OF REVERSE MIGRATION?

A. Yes. The Company's proposal is discussed in the testimony of Mr. Czekanski. Although my analysis shows that the cost impact was largely mitigated because of the capacity-assignment process, the Company recognizes that there is a potential for the costs to service reverse migration customers to differ from the prices available to sales customers under the GPP, both positively and negatively. Therefore, the Company is proposing to implement a surcharge tariff that would allow the Company to account for that difference.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

Exhibit GLB-1

Estimated Cost of Gas for Re-migration Customers versus Cost of Gas for Firm Sales Customers

	Jul-02	Aug-02	Sep-02	Oct-02	Nov-02	Dec-02	Jan-03	Feb-03	Mar-03	
1 FT-1										
2 FT-1 Re-migration Gas Costs	**$2,756**	**$2,802**	**$21,487**	**$50,316**	**$113,286**	**$169,477**	**$284,174**	**$270,862**	**$434,117**	
3 FT-1 Re-migration Dekatherms	604	604	3,618	10,112	21,985	32,398	40,138	37,678	40,714	
4 Average Cost	$4.56	$4.64	$5.94	$4.98	$5.15	$5.23	$7.08	$7.19	$10.66	
	Jul-02	Aug-02	Sep-02	Oct-02	Nov-02	Dec-02	Jan-03	Feb-03	Mar-03	
5 FT-2										
6 FT-2 Re-migration Gas Costs	**$1,797**	**$2,567**	**$9,358**	**$21,856**	**$68,946**	**$119,581**	**$157,420**	**$203,840**	**$272,130**	
7 FT-2 Re-migration Dekatherms	278	305	1,246	3,638	12,074	22,051	25,899	30,504	27,218	
8 Average Cost $/Dth	$6.46	$8.42	$7.51	$6.01	$5.71	$5.42	$6.08	$6.68	$10.00	
Combined Average Monthly Re-migration Costs										
	Jul-02	Aug-02	Sep-02	Oct-02	Nov-02	Dec-02	Jan-03	Feb-03	Mar-03	
9 FT-1 and FT-2										
10 Total Gas costs	$4,553	$5,369	$30,844	$72,172	$182,232	$289,058	$441,594	$474,702	$706,247	
11 Total Dekatherms	882	909	4,864	13,750	34,059	54,449	66,037	68,182	67,932	
12 Average Cost $/Dth	$5.16	$5.91	$6.34	$5.25	$5.35	$5.31	$6.69	$6.96	$10.40	
13 **Average cost of Sales Sendout $/Dth**	$7.24	$7.44	$7.10	$5.89	$5.22	$5.26	$5.65	$6.56	$6.85	
14 Difference	-$2.07	-$1.54	-$0.75	-$0.64	$0.13	$0.05	$1.04	$0.41	$3.55	
15 **Difference X Total Re-migrated Dths**	**-$1,830**	**-$1,396**	**-$3,666**	**-$8,843**	**$4,444**	**$2,711**	**$68,749**	**$27,633**	**$240,981**	**$328,784**

FT-1 Re-migration Cost Estimate

Sales	Jul-02	Aug-02	Sep-02	Oct-02	Nov-02	Dec-02	Jan-03	Feb-03	Mar-03	Total
1 Assigned Capacity MDQ (Dekatherms/day)	41	58	591	626	855	909	960	1,276	1,286	
2 Total Re-migration Sales	604	604	3,618	10,112	21,985	32,398	40,138	37,678	40,714	187,851
3 Pipeline Capability (1)	604	604	3,618	10,112	21,985	28,179	29,760	35,728	39,866	170,456
4 Incremental Requirements (2)	0	0	0	0	0	4,219	10,378	1,950	848	17,395

Unit Cost of Supplies Delivered	Jul-02	Aug-02	Sep-02	Oct-02	Nov-02	Dec-02	Jan-03	Feb-03	Mar-03
5 Pipeline (1) Tennessee Zn 1	$3.57	$3.24	$3.58	$4.07	$4.56	$4.58	$5.39	$6.23	$10.01
6 Pipeline (1) M3/AGT	$3.72	$3.34	$3.63	$4.17	$4.79	$5.05	$6.20	$7.23	$11.75
7 Pro Rata Pipeline (90% Tenn - 10% M3/AGT) (3)	$3.58	$3.25	$3.59	$4.08	$4.59	$4.63	$5.47	$6.33	$10.18
8 Incremental Cost - Daily Supply (2)	$0.00	$0.00	$0.00	$0.00	$0.00	$6.11	$10.33	$13.33	$11.08

Commodity Cost of Sales to Re-migrated FT-1 Customers	Jul-02	Aug-02	Sep-02	Oct-02	Nov-02	Dec-02	Jan-03	Feb-03	Mar-03	Totals
9 Pipeline Supply (1)	$2,163	$1,965	$12,976	$41,253	$100,845	$130,403	$162,895	$226,282	$405,969	$1,084,752
10 Incremental Supply (2)	$0	$0	$0	$0	$0	$25,778	$107,205	$25,994	$9,396	$168,372
11 **Total Commodity Gas Cost**	**$2,163**	**$1,965**	**$12,976**	**$41,253**	**$100,845**	**$156,181**	**$270,100**	**$252,276**	**$415,364**	**$1,253,124**

Demand Cost Allocated to Re-Migrated FT-1 Customers	Jul-02	Aug-02	Sep-02	Oct-02	Nov-02	Dec-02	Jan-03	Feb-03	Mar-03	Totals
12 Assigned Capacity MDQ (Dekatherms/day)	41	58	591	626	855	909	960	1,276	1,286	
13 Tennessee ZN1 Demand Charge ($/Dth)	$15.22	$15.22	$15.22	$15.22	$15.22	$15.22	$15.20	$15.20	$15.20	
14 AGT M3 to City Gate Demand Charge ($/Dth)	$6.59	$6.59	$6.59	$6.59	$6.59	$6.59	$6.59	$6.59	$6.59	
15 Tennessee ZN1/M3 AGT Pro rata demand (3)	$14.35	$14.35	$14.35	$14.35	$14.35	$14.35	$14.34	$14.34	$14.34	
16 AGT M3 Demand Surchage (4)	$0.08	$0.08	$0.08	$0.08	$0.08	$0.08	$0.08	$0.08	$0.08	
17 Pipeline Demand Cost	$588	$832	$8,483	$8,985	$12,272	$13,047	$13,765	$18,296	$18,439	**$94,707**
18 Demand Surcharge Cost	$5	$5	$28	$78	$169	$249	$309	$290	$313	**$1,446**
19 **Total Demand Cost**	**$593**	**$837**	**$8,510**	**$9,063**	**$12,441**	**$13,296**	**$14,074**	**$18,586**	**$18,753**	**$96,154**
20 **Total Commodity and Demand**	**$2,756**	**$2,802**	**$21,487**	**$50,316**	**$113,286**	**$169,477**	**$284,174**	**$270,862**	**$434,117**	$\boxed{\textbf{\$1,349,278}}$

(1) Pipeline supply available from the return of the assigned capacity, assumed to be purchased at first-of-the-month pricing.

(2) Incremental requirements are the purchases needed to meet demand above that available from the returning assigned capacity. Pricing is based on the highest cost supply used each day, weighted by degree days in excess of the level which would cover load equal to the returned capacity. Workpaper 1 shows the calculation of the price.

(3) Pipeline capacity returning from assignment was pro-rated at 90% Tennessee ZN1 and 10% Algonquin M3 to City Gate. The Demand and Commodity Charges of each capacity is pro-rated using the 90/10 split to calculate a blended rate.

(4) Marketers are either charged a surcharge or receive a credit to equalize the value of their selected capacity and the average system capacity cost. Algonquin M3 capacity has a $.077/Dth surcharge. The surcharge was applied to 10%, the Algonquin portion, of the volumes.

FT-2 Re-migration Cost Estimate

Sales	Jul-02	Aug-02	Sep-02	Oct-02	Nov-02	Dec-02	Jan-03	Feb-03	Mar-03	Total
1 Assigned Capacity MDQ in Dekatherms	47	100	303	373	561	573	586	689	691	
2 Total Re-migration Sales	278	305	1,246	3,638	12,074	22,051	25,899	30,504	27,718	123,713
3 Pipeline Capability (1)	278	305	1,238	3,638	12,074	17,763	18,166	19,292	21,421	94,175
4 Storage used (2)	0	0	0	0	0	3,810	5,441	9,392	5,612	24,255
5 LNG used (2)	0	0	0	0	0	478	2,292	1,820	685	5,275

Unit Cost of Supplies Delivered	Jul-02	Aug-02	Sep-02	Oct-02	Nov-02	Dec-02	Jan-03	Feb-03	Mar-03
6 Pipeline (1) Tennessee Zn 1	$3.57	$3.24	$3.58	$4.07	$4.56	$4.58	$5.39	$6.23	$10.01
7 Pipeline (1) M3/AGT	$3.72	$3.34	$3.63	$4.17	$4.79	$5.05	$6.20	$7.23	$11.75
8 Pro Rata Pipeline (90% Tenn - 10% M3/AGT) (3)	$3.58	$3.25	$3.59	$4.08	$4.59	$4.63	$5.47	$6.33	$10.18
9 Storage (2)	$0.00	$0.00	$0.00	$0.00	$0.00	$4.23	$4.23	$4.23	$4.45
10 LNG (2)	$0.00	$0.00	$0.00	$0.00	$0.00	$6.21	$6.43	$9.96	$9.45

Commodity Cost of Sales to Re-migrated FT-2 Customers	Jul-02	Aug-02	Sep-02	Oct-02	Nov-02	Dec-02	Jan-03	Feb-03	Mar-03	Totals
11 Pipeline Supply (1)	$996	$992	$4,440	$14,842	$55,383	$82,201	$99,434	$122,185	$218,137	$598,611
12 Storage (2)	$0	$0	$0	$0	$0	$16,124	$23,018	$39,735	$24,959	$103,836
13 LNG (2)	$0	$0	$0	$0	$0	$2,967	$14,746	$18,119	$6,475	$42,307
14 Total Commodity Gas Cost	$996	$992	$4,440	$14,842	$55,383	$101,292	$137,198	$180,039	$249,571	$744,754

Returning Pipeline and Storage Capacity Demand costs - Re-migrated FT-2 customers	Jul-02	Aug-02	Sep-02	Oct-02	Nov-02	Dec-02	Jan-03	Feb-03	Mar-03	
15 Assigned Capacity MDQ in Dekatherms	47	100	303	373	561	573	586	689	691	
16 Tennessee ZN1 Demand Charge ($/Dth)	$15.22	$15.22	$15.22	$15.22	$15.22	$15.22	$15.20	$15.20	$15.20	
17 AGT M3 to City Gate Demand Charge ($/Dth)	$6.59	$6.59	$6.59	$6.59	$6.59	$6.59	$6.59	$6.59	$6.59	
18 Tennessee ZN1/M3 AGT Pro rata demand (3)	$14.35	$14.35	$14.35	$14.35	$14.35	$14.35	$14.34	$14.34	$14.34	
19 AGT M3 Demand Surchage (4)	$0.08	$0.08	$0.08	$0.08	$0.08	$0.08	$0.08	$0.08	$0.08	
20 Pipeline Demand Cost	$675	$1,435	$4,349	$5,354	$8,052	$8,224	$8,402	$9,879	$9,908	$56,278
21 Demand Surcharge Cost	$2	$2	$10	$28	$93	$170	$199	$235	$213	$953
22 Storage Demand	$125	$137	$559	$1,632	$5,418	$9,894	$11,621	$13,687	$12,437	$55,510
23 Total Demand Costs	$801	$1,574	$4,918	$7,014	$13,563	$18,288	$20,223	$23,801	$22,558	$112,741
24 Total Commodity and Demand	$1,797	$2,567	$9,358	$21,856	$68,946	$119,581	$157,420	$203,840	$272,130	$857,494

(1) Pipeline supply available from the return of the assigned capacity, assumed to be purchased at first-of-the-month pricing.

(2) Re-migration of FT-2 Customers returns the underground storage and LNG capacity and extinguishes the obligation to deliver nominated storage and LNG supplies to marketers for that customer.

(3) Pipeline capacity returning from assignment was pro-rated 90% Tennessee ZN1 and 10% Algonquin M3 to City Gate. The Demand and Commodity Charges of each capacity is pro-rated using the 90/10 split to calculate a blended rate.

(4) Marketers are either charged a surcharge or receive a credit to equalize the value of their selected capacity and the average system capacity cost. Algonquin M3 capacity has a $.077/Dth surcharge. The surcharge was applied to 10%, the Algonquin portion, of the volumes.

Exhibit GLB-4

Re-migration Sales as a percentage of Firm Sales

	Jul-02	Aug-02	Sep-02	Oct-02	Nov-02	Dec-02	Jan-03	Feb-03	Mar-03	Total
1 Firm Sales Sendout	700,279	692,332	798,084	1,847,005	3,062,587	4,638,795	5,976,902	5,054,969	3,828,887	26,599,840
2 Total Re-migrated Transportation	681	909	4,864	13,750	34,059	54,449	66,037	68,183	67,933	310,865
3 Re-migration as a percent of Total	0.10%	0.13%	0.61%	0.74%	1.11%	1.17%	1.10%	1.35%	1.77%	1.2%

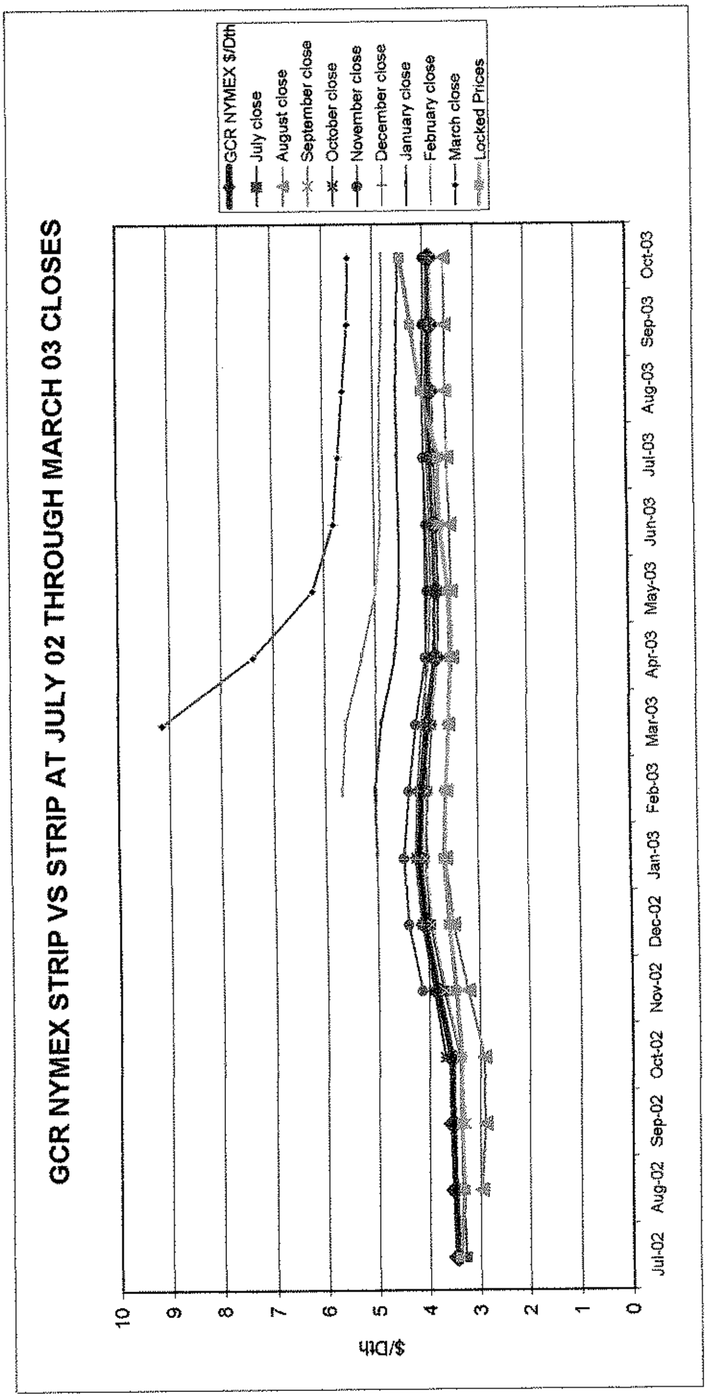
Re-migration Gas Costs as a percentage of Total Gas Costs

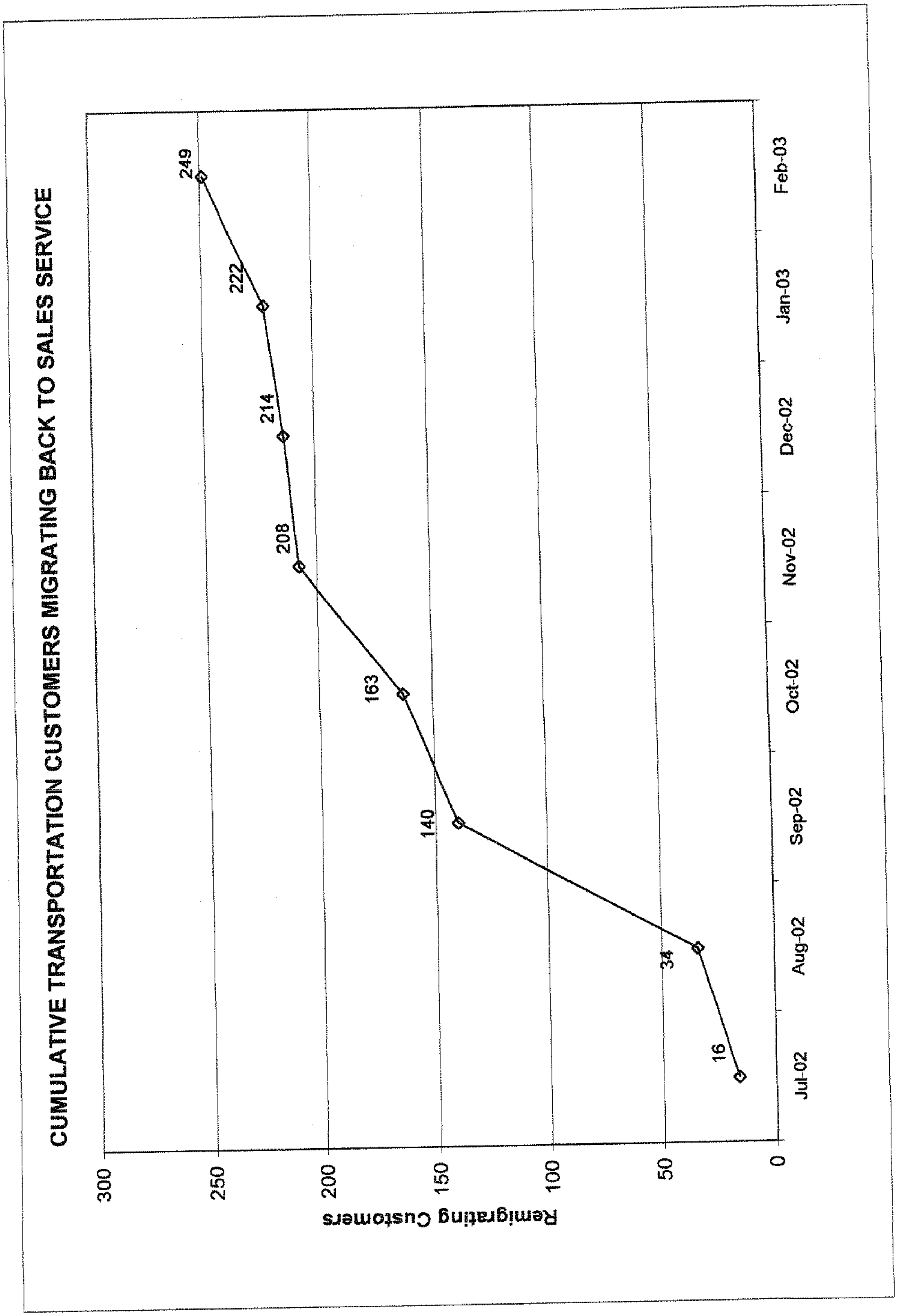
	Jul-02	Aug-02	Sep-02	Oct-02	Nov-02	Dec-02	Jan-03	Feb-03	Mar-03	Total
4 Total Firm Gas Costs	$5,067,922	$5,152,088	$5,662,767	$10,883,457	$15,986,248	$24,397,113	$33,743,864	$33,146,698	$26,222,904	$160,263,061
5 Total Re-migrated Gas Costs	$4,553	$5,369	$30,844	$72,172	$182,232	$289,058	$441,594	$474,702	$706,247	$2,206,772
6 Re-migration as a percent of Total	0.09%	0.10%	0.54%	0.66%	1.14%	1.18%	1.31%	1.43%	2.69%	1.4%

Average cost of Firm Gas Costs Calculation

	Jul-02	Aug-02	Sep-02	Oct-02	Nov-02	Dec-02	Jan-03	Feb-03	Mar-03	Total
7 Total Firm Gas Costs	$5,067,922	$5,152,088	$5,662,767	$10,883,457	$15,986,248	$24,397,113	$33,743,864	$33,146,698	$26,222,904	160,263,061
8 Firm Sales Sendout	700,279	692,332	798,084	1,847,005	3,062,587	4,638,795	5,976,902	5,054,969	3,828,887	26,599,840
9 Average cost of Gas	$7.24	$7.44	$7.10	$5.89	$5.22	$5.26	$5.65	$6.56	$6.85	$6.02

Exhibit GLB-5




CUMULATIVE TRANSPORTATION CUSTOMERS MIGRATING BACK TO SALES SERVICE
Remigrating Customers
300
250
200
150
100
50
0
Jul-02
Aug-02
Sep-02
Oct-02
Nov-02
Dec-02
Jan-03
Feb-03
16
34
140
163
208
214
222
249